BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. E-7, SUB 1146

In the Matter of		
Application of Duke Energy Carolinas, LLC, for Adjustment of Rates and Charges Applicable to Electric Utility Service in North Carolina	)))))	TESTIMONY OF JACK L. FLOYD PUBLIC STAFF – NORTH CAROLINA UTILITIES COMMISSION

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TESTIMONY OF JACK L. FLOYD
ON BEHALF OF THE PUBLIC STAFF
NORTH CAROLINA UTILITIES COMMISSION

JANUARY 23, 2018

Q. PLEASE STATE YOUR NAME, BUSINESS ADDRESS, AND PRESENT POSITION.

A. My name is Jack L. Floyd. My business address is 430 North Salisbury Street, Dobbs Building, Raleigh, North Carolina. I am an Engineer with the Electric Division of the Public Staff – North Carolina Utilities Commission.

Q. BRIEFLY STATE YOUR QUALIFICATIONS AND DUTIES.

A. My qualifications and duties are included in Appendix A.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of my testimony is to present the Public Staff's analysis and recommendations concerning: (1) the cost-of-service study (COSS) used by Duke Energy Carolinas, LLC (DEC or the Company) in this case and the Company's adjustment to the COSS; (2) the class rates of return (ROR) on rate base under present revenues; (3)

DEC's proposed additions or modifications to certain rate schedules; (4) the Customer Connect Project to develop and implement a new billing and customer information system among many Duke Energy Corporation (DE) affiliates; and (5) the Company's deployment of smart meters. The Public Staff's recommendations are based on a review of the application filed by DEC, the testimony and exhibits (direct and supplemental) of DEC's witnesses, and DEC's responses to numerous data requests from the Public Staff and other intervenors to this proceeding.

Q. PLEASE SUMMARIZE YOUR TESTIMONY AND YOUR RECOMMENDATIONS.

A. I have reviewed the testimony and exhibits of Company witnesses Cowling, Fountain, Hager, Hunsicker, McManeus, Pirro, and Schneider, along with other information provided in response to data requests, regarding cost-of-service, rate design and revenue apportionment, and the Company's preparations and deployment of its proposed Customer Connect Project and smart meters.

More specifically, my testimony recommends the following:

1. That for purposes of this proceeding, the Public Staff does not object to the Company's use of the summer coincident peak cost-of-service methodology;
2. That DEC's adjustment in the COSS to reflect the peak demand and energy sales related to wholesale contracts that are expiring in 2017 is appropriate;

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3. That any proposed revenue change be apportioned to the customer classes, especially for the lighting class, such that:

   a. Class RORs are within a band of reasonableness of $\pm$ 10% relative to the overall NC retail ROR;

   b. All class RORs move closer to parity with the NC retail ROR;

   c. The revenue increase to any one customer class is limited to no more than two percentage points greater than the NC retail jurisdictional percentage increase, with priority given to the percentage increase versus the ROR band of reasonableness; and

   d. Subsidization among the customer classes is minimized;

4. That any changes to the basic facilities charges should be limited as follows:

   a. For any revenue increase, the basic facilities charge increase for the residential class should be limited to recover no more than 25% of the total approved revenue increase assigned to that customer class; and,

   b. For any revenue decrease, the basic facilities charge for the residential class should remain unchanged;

5. That the Company should consider offering an extended payment option to customers served under Schedules GL and PL who desire LED services;

6. That the Company should file semi-annual reports on the progress of its mercury vapor lighting replacement program, including the revenue impact associated with those fixtures;

7. That the Company should meet with its municipal customers in order to develop proposed changes to Schedules GL and PL to bring parity to the rates for equivalent light emitting diode (LED) luminaires in Schedules GL and PL, in order to effectuate the consolidation of these schedules in a future proceeding;

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8. That the Commission find that the amount of expenses related to the initial work on Customer Connect Project included in this case is reasonable;

9. That DEC provide semiannual reports on the status of its implementation of the Customer Connect Project;

10. That the Commission conclude the AMI opt-out proceeding in the Docket No. E-7, Sub 1115 by ruling on the matter along with this general rate case; and

11. That the Company include certain AMI deployment-related information in its next rate case.

COST-OF-SERVICE STUDY

Q. PLEASE BRIEFLY EXPLAIN THE PURPOSE OF THE COSS AND HOW IT IS USED IN THIS PROCEEDING.

A. The purpose of a COSS is to determine the share of system revenues, expenses, and plant that should be assigned or allocated to a particular jurisdiction and customer class. The COSS uses the demand and energy consumption data of the jurisdictions and customer classes, as well as the resources used by the Company and the tasks performed by the Company to provide utility service, and assigns or allocates the revenues, expenses, and plant associated with each resource and task to measure each class's contribution to the Company's overall cost of service.

The underlying principle is that each jurisdiction, customer class, or customer should be responsible for an appropriate share of the costs that are planned for and incurred in order to serve it. Some costs can be directly assigned. Costs that cannot be directly assigned should be allocated using a methodology that most accurately and

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equitably reflects this underlying principle. Specifically with respect to production plant, the cost-of-service methodology should be reflective of the use for which generation is planned and costs are incurred to operate.

Q. WHAT COST–OF–SERVICE METHODOLOGY HAS DEC PROPOSED FOR USE IN THIS PROCEEDING?

A. DEC has proposed using the summer coincident peak (SCP) methodology to determine both jurisdictional and customer class cost responsibility in this case. Under the SCP methodology, production plant and related expenses, such as depreciation and accumulated depreciation, purchased power capacity costs, and certain production operation and maintenance (O&M) costs are allocated based on the loads (that is, the level of demand) of a jurisdiction and its customers during just one specific hour of the year -- the summer system peak hour. All other hours of the year are not recognized under this methodology for the purpose of allocating production plant cost responsibility to the North Carolina jurisdiction and its customer classes.

Q. IS THE SUMMER COINCIDENT PEAK THE SYSTEM PEAK FOR THE TEST YEAR?

A. Yes. The actual system peak (18,022 MWs as adjusted for wholesale load) for the test year period occurred July 27, 2016.

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Q. DID YOU EVALUATE OTHER COST-OF-SERVICE METHODOLOGIES IN THIS CASE?

A. Yes. The Public Staff also reviewed the Company's filed summer/winter coincident peak and average (SWPA) methodology.

Q. DOES THE PUBLIC STAFF AGREE WITH DEC'S USE OF THE SCP COST-OF-SERVICE METHODOLOGY?

A. For purposes of this proceeding, the Public Staff does not object to the Company's use of the SCP cost-of-service methodology. The Public Staff has historically supported, and continues to support, use of a COSS methodology that gives weight to both peak demand and average demand, e.g., the SWPA methodology, because such a methodology appropriately allocates production plant costs in a way that most accurately reflects the Company's generation planning and operation. Unlike other methodologies that allocate 100% of the production plant costs based on one single hour out of 8,760 total hours in a year, a peak and average methodology recognizes that a portion of plant costs, particularly for base and intermediate load generation, is incurred to meet energy requirements throughout the year and not solely to meet peak demand at one single hour. In addition, an SCP methodology, or any other methodology based solely on one or a handful of peak hours, allows some customer classes to escape cost responsibility for production plant, despite benefitting from it.

Q. WHY ARE YOU NOT ADVOCATING THE SWPA METHODOLOGY IN THIS PROCEEDING?

A. In this proceeding, the differences between the per books calculations of revenue requirement between the SCP and SWPA methodologies is immaterial on a jurisdictional basis. As represented in the Company's Form E-1, Item 45A, the difference between the two methodologies for the NC retail jurisdiction is approximately $54,000. In other words, the SCP methodology allocates $54,000 more to the NC retail jurisdiction than does the SWPA methodology. The differences between the revenue assignments to individual customer classes between the two methodologies are more pronounced, however. Given the small difference on a jurisdictional basis, the Public Staff does not object to the Company's use of the SCP methodology for purposes of this case.

Q. DO YOU HAVE A SUMMARY OF THE DIFFERENCES RESULTING FROM THE TWO COST-OF-SERVICE METHODOLOGIES IN THIS PROCEEDING?

A. Yes. Table 1 below compares the total electric revenue requirement for the North Carolina retail jurisdiction and customer classes using DEC's "per books" COSS for the SCP and SWPA methodologies.

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Table 1. Comparison of the Total Electric Revenue Requirement

	SCP [$000]	SWPA [$000]	Difference (SCP minus SWPA) [$000]
NC Retail	4,991,300	4,991,246	54
Residential Class	2,281,916	2,281,484	432
General Service Class	902,760	902,046	714
Lighting Class	139,085	139,281	(216)
Industrial Class	165,175	165,249	(74)
OPT Class	1,502,384	1,503,186	(802)

Source: Form E-1, Item 45 A for each methodology.

A positive difference means that the SCP methodology allocates more to the jurisdiction or class. A negative difference means the SWPA allocates more costs.

Q. DID DEC MAKE ANY PRO FORMA ADJUSTMENTS TO ITS COSS ALLOCATION FACTORS?

A. Yes. Witness Hager describes an adjustment to the peak demand and energy sales related to wholesale contracts that are expiring in 2017. I reviewed the Company's test year peak demand and energy

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sales data related to this adjustment and believe the adjustment is appropriate for this proceeding.

REVENUES AND RATE DESIGN

Q. PLEASE DISCUSS THE RELATIONSHIP BETWEEN A COSS AND RATE DESIGN.

A. Rate design should follow the same cost causation approach underlying the COSS, such that each customer class, or customer, is responsible for an appropriate share of the costs that are planned for and incurred in order to serve them. However, strict adherence to this cost causation principle may not always be possible if doing so would result in "rate shock" for certain customers or customer classes. In addition, and depending on the COSS methodology utilized, cost responsibility results can vary significantly due to unusual events that occur in the test year. The COSS functionalizes costs, thus providing a basis from which to start rate design, but which does not necessarily dictate the rate design. Other considerations and objectives, such as undue impacts on low usage customers, must also be considered when developing rate design. I will address an example of this consideration later in my testimony regarding the basic facilities charge (BFC).

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Q. PLEASE DISCUSS THE PUBLIC STAFF'S GOALS IN ASSIGNING A PROPOSED REVENUE INCREASE.

A. In general, the Public Staff believes that assignment of a proposed revenue change (increase or decrease) should be grounded in four fundamental principles. Using the ROR as determined by the COSS, and incorporating all adjustments and allocation factors associated with the proposed revenue change, the Public Staff seeks to:

1. Limit any revenue increase assigned to any customer class such that each class is assigned an increase that is no more than two percentage points greater than the overall jurisdictional revenue percentage increase, thus avoiding rate shock;

2. Maintain a ±10% “band of reasonableness” for RORs, relative to the overall jurisdictional ROR such that to the extent possible, the class ROR stays within this band of reasonableness following assignment of the proposed revenue changes;

3. Move each customer class toward parity with the overall jurisdictional ROR; and

4. Minimize subsidization of customer classes by other customer classes.

Q. DID THE COMPANY ADHERE TO THESE PRINCIPLES IN ITS ASSIGNMENT OF ITS PROPOSED REVENUE INCREASE?

A. Regarding the first principle related to the percentage of the revenue increase, a review of Pirro Exhibit 2, Column "M" indicates that on a total revenue basis (Column M of the exhibit excludes the impacts of Rider GRR), only the residential class is assigned an increase that exceeds two percentage points above the revenue increase assigned to the NC retail jurisdiction. Including the impact of the revenues associated with Rider GRR (right-most column in Pirro Exhibit 2), the residential class still is assigned an increase of more than two percentage points above the total revenue increase assigned to the NC Retail jurisdiction.

A review of the RORs calculated by the Company as found in its filed Form E-1, Item 45C, indicates that the assignment of the Company's proposed revenue increase complies with the second principle for the residential and OPT classes only. The general service, industrial, and lighting classes exceed the ± 10% band of reasonableness.

With respect to the third principle, the Company's assignment of the proposed increase does move each customer class closer to parity with the NC retail jurisdiction ROR.

With respect to the fourth principle of reducing subsidization, Witness Pirro did take subsidization into account in his calculations of revenue requirement by reducing the difference between class RORs and the overall jurisdictional ROR when assigning revenue to the customer classes.

Q. DO YOU AGREE WITH THE MANNER IN WHICH THE COMPANY ASSIGNED ITS PROPOSED REVENUE INCREASE?

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A. Generally, I agree with the Company's approach. I believe the Company's effort to address 25% of the cross-subsidization issue is reasonable. While more could be done to meet the principles outlined above, avoidance of rate shock is a significant consideration. According to the Company's Form E-1, Item 45C under the SCP methodology, the general service, industrial, and lighting customer classes have an ROR more than 10% above the 7.29% jurisdictional ROR. However, the Company has assigned a revenue increase to the residential class that is more than two percentage points above the NC Retail jurisdiction.[1]

Q. WHAT IS YOUR RECOMMENDATION REGARDING THIS CONFLICT WITH THE PUBLIC STAFF'S FIRST TWO PRINCIPLES?

A. With respect to the assignment of any potential revenue increase, I believe the first priority should be to keep the increase assigned to any class to no more than two percentage points above the overall jurisdictional revenue increase, while also working to move all classes closer to parity with the jurisdictional ROR. This prioritization places the focus on the total dollar increase customers will experience, while moving all customers toward a more balanced cost-of-service. I recommend the Company assign any revenue

[1] See Pirro Exhibit 2, Column "M."

increase resulting from this proceeding such that no customer class receives an increase of more than two percentage points above the jurisdictional percentage increase, and to the extent possible move all customer classes toward parity with the NC Retail jurisdictional ROR, particularly for the lighting class as I will discuss in more detail later.

In the event of a revenue decrease, as recommended by Public Staff witness Boswell, I believe it is appropriate to focus on addressing any disparities in the class RORs. In addressing disparities in RORs, any revenue decreases assigned to individual customer classes should be limited so that no other customer class sees an increase in its assigned revenue requirement. In other words, in the event of a revenue requirement decrease, no customer class should see an increase simply to bring the class ROR within 10% of the jurisdictional ROR.

Q. DO YOU HAVE ANY COMMENTS OR RECOMMENDATIONS CONCERNING ANY OF THE COMPANY'S PROPOSED RATE SCHEDULES OR RIDERS?

A. Yes. I am generally supportive of the Company's proposed changes to its rate schedules, riders, and service regulations as discussed by Witness Pirro. Other than proposed changes to the lighting rate schedules, the Company did not propose substantial changes to the

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structure of its rate schedules in this proceeding. As stated by Witness Pirro, the Company based this approach on the Company's ongoing efforts to deploy smart meters. Mr. Pirro indicates that the Company has committed to developing new rate designs in the future once smart meters are fully deployed and data from those meters becomes available. This is a reasonable approach, so long as the Company is expeditious in its efforts to develop these new rate designs. As indicated by Witnesses Fountain, Hunsicker, and Pirro, the Company has committed to develop new and innovative rate designs that will modernize how customers receive electric service and provide customers with the ability to exercise control over their use of electricity. The Public Staff stands willing to work with the Company to develop these innovative rate designs.

Nevertheless, there are some rate issues that should be addressed in this proceeding. These issues are: (1) the BFC, (2) stand-by charges, and (3) lighting.

Q. PLEASE DISCUSS DEC'S PROPOSED CHANGES TO THE BFC.

A. DEC has proposed increasing the BFC by 51% for residential rate schedules from the current charge of $11.80 per month to $17.79 per month. The Company's unit COSS as illustrated in Form E-1, Item 45E under its proposed rates indicates a customer unit cost of $23.59 per month. While the Company has not proposed a BFC equivalent

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to the level suggested by the COSS, I do not agree with the magnitude of the Company's proposed increase to the BFC for two reasons.

First, I believe the large revenue increase derived from the requested BFC as proposed in this proceeding is unreasonable given the impact on low usage customers. In this proceeding, if DEC is granted its requested rate increase, approximately 45% of the total revenue increase from DEC's proposed revenues for Schedule RS will come solely from the increase in the BFC. Secondly, a review of customer bills under Schedule RS indicates that approximately 68% of all bills in the test year were for energy consumption of 1,200 kWh and less. The BFC is an unavoidable charge, and constitutes a large percentage of residential customer bills, particularly those with low usage.

DEC's proposal to move the BFC toward its calculated unit cost is appropriate. However, the amount of the revenue increase derived from the BFC should be limited.

Q. WHAT IS YOUR RECOMMENDATION CONCERNING THE BFC?

A. I recommend that if a revenue increase is approved, DEC should be allowed to increase its BFC for the residential class to recover up to 25% of the approved revenue increase assigned to that customer class. Under the Company's proposed revenue increase of

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approximately $612 million, this produces a BFC of approximately $15.10 for Schedule RS. My recommendation also moves the BFC closer to the calculated unit cost under DEC's proposed revenues. Ultimately the BFC approved for the residential class should be commensurate with any residential revenue increase that may be approved by the Commission, such that the residential BFC revenue increase does not exceed 25% of the total residential class revenue increase.

Q. WHAT IS YOUR RECOMMENDATION CONCERNING THE BFC IF THERE IS A REVENUE DECREASE RESULTING FROM THIS PROCEEDING?

A. If the Commission were to order a decrease in the revenue requirement as a result of this proceeding, I recommend that the BFCs remain unchanged from current rates.

Q. PLEASE ADDRESS THE ISSUE OF STAND-BY CHARGES.

A. In its Sub 1026 proceeding, the Commission required DEC to evaluate stand-by charges in the next general rate case proceeding.[2] Witness Pirro indicated in his testimony, and the Company further responded to the Public Staff's data request, that the Company

[2] Ordering paragraph 30 in the September 24, 2013 *Order Granting General Rate Increase,* in Docket No. E-7, Sub 1026 (Sub 1026 Order).

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intended to address the issue of stand-by charges in the context of net metering. The Company anticipates the Commission initiating a proceeding later this year to address net metering and related topics pursuant to House Bill 589.[3] Given the Company's proposed continuation of the current structure for stand-by charges until the net metering proceeding, and the small increase proposed for the rate itself, I consider the Company's proposal to be reasonable at this time.

Q. PLEASE DISCUSS THE COMPANY'S PROPOSED CHANGES FOR LIGHTING SERVICE.

A. DEC has proposed major changes to its area (Schedules FL, NL, and OL) and street lighting (Schedules GL and PL) rate schedules. Those changes include: (1) reducing the transition fee associated with replacing existing metal halide (MH) and high pressure sodium (HPS) light fixtures with light emitting diode (LED) technology; (2) initiating a proactive strategy to replace existing mercury vapor (MV) fixtures; (3) closing Schedule NL; and (4) closing Schedule FL and merging the fixtures in Schedule FL into Schedules OL and GL. The Company's filing did not address moving the rates contained in Schedules GL and PL to parity with each other as has been discussed since the Company's general rate case in Docket No. E-

[3] See G.S. 62-126.4.

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7, Sub 909. My testimony responds to each of these items.

Q. BRIEFLY ELABORATE ON THE RECENT HISTORY OF DEC'S LIGHTING SERVICES.

A. In the Sub 1026 Order, the Commission required DEC to undertake several lighting-related tasks. Those tasks involved (1) providing the Public Staff with the algorithms used to develop individual fixture rates for lighting services; (2) developing new LED lighting options; and (3) completing the alignment of the rates in Schedules GL and PL. Following the Sub 1026 rate case, DEC provided its algorithms to the Public Staff. DEC and Duke Energy Progress, LLC (DEP), also held meetings across the state to discuss lighting related issues with municipal customers. The purpose of these meetings was to help municipal customers better understand the Company's lighting services, as well as give DEC and DEP some important feedback on the types of lighting services and payment options preferred by municipal customers. However, the completion of the alignment of Schedule GL rates with those in Schedule PL for the same fixtures has proven to be more difficult than originally expected due to issues of rate shock. I will discuss this process of bringing together the rates in Schedules GL and PL later.

Since the Sub 1026 rate case, the Commission has granted approval to several DEC lighting-related initiatives, mostly around the

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implementation of new LED offerings, approving transition fees for MH and HPS fixtures that are replaced with LED before they are fully depreciated, and approving the proactive replacement of MV and MH fixtures that have reached obsolescence.[4]

Q. PLEASE DISCUSS THE COMPANY'S PROPOSED REDUCTIONS IN THE TRANSITION FEES APPLICABLE TO LED LIGHTING FIXTURES.

A. The Company received initial approval of a transition fee in Docket No. E-7, Sub 1094. The intent of the transition fee was to allow the Company to offer customers who desired LED lighting services the opportunity to transition from an existing MH or HPS fixture to LED sooner rather than later, while balancing the need to avoid stranded costs associated with the premature retirement of the MH or HPS fixture.[5] In response to the Public Staff's data request, DEC indicated that it received approximately $566,000 in transition fee revenues from 2015 through June 2017; however, only $2,949 of these revenues were identified as test year revenues. Additionally, the Company indicated that the customer transition to LED fixtures

[4] See orders dated October 10, 2014 in Docket Nos. E-7, Sub 1026; October 13, 2015 in Docket No. E-7, Sub 1094; June 21, 2016 in Docket No. E-7, Sub 1114; and August 1, 2017 in Docket No. E-7, Sub 1149.

[5] MV fixture replacement was not assessed a similar transition fee because MV technology had become obsolete and replacement of these fixtures was not considered premature retirement.

has been slower than expected.

In order to address the slower pace, DEC proposes to reduce its transition fees by approximately 21% to 27%, depending upon the rate schedule and transitioning fixture. The Company indicated that its goal was to balance the desire of customers to have LED services against a potential rush for LED services and the need to mitigate stranded costs associated with fixtures that were not fully depreciated. In a confidential response to the Public Staff's data request, the Company provided an estimate of the net book value associated with this transition program. The transition fee for conversion of MH or HPS fixtures that have not yet been fully depreciated, is set at an amount to ensure that customers seeking conversion to LED bear the cost responsibility rather than the lighting class as a whole.

Q. DO YOU AGREE WITH DEC'S PROPOSED TRANSITION FEES FOR LED SERVICE?

A. Yes. The reduced transition fees proposed by DEC reasonably balance the desire of customers for LED service, with the need to transition lighting in an orderly manner, while minimizing the adverse impact of stranded costs on the remaining lighting class. The Public Staff continues to support the advancement of LED lighting technology, which is consistent with Commission Rule R8-47

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regarding energy efficient lighting services.

Q. IS THERE A WAY TO MITIGATE THE COST IMPACT TO CUSTOMERS WHO DESIRE TO TRANSITION TO LED LIGHTING?

A. Yes. I believe the Company should consider providing an extended payment option for municipalities and other customers who desire LED services, but struggle with budgeting issues that prevent them from participating. For example, one option could be to allow the transition fees to be paid over a 2 to 4 year period.

The Public Staff has discussed the transition to LED with representatives of the North Carolina League of Municipalities (NCLM). The NCLM has indicated to the Public Staff that the transition fees are a formidable barrier to smaller municipalities that desire LED services, but cannot tolerate the current fee impact. Longer payment periods should help mitigate the impact.

Q. PLEASE DISCUSS THE COMPANY'S PROPOSED PLAN TO BEGIN A PROACTIVE REPLACEMENT OF MV FIXTURES PROVIDED UNDER SCHEDULE PL.

A. The Company is requesting approval to begin a more aggressive replacement program for its existing MV fixtures, similar to the replacement program approved by the Commission on June 21,

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2016, in Docket No. E-7, Sub 1114. In the Sub 1114 proceeding the Commission approved a plan to move MV fixtures served under Schedule OL from a casual replacement program (where replace occurs upon failure or at customer request), to a more proactive plan. The Company stated in Sub 1114 that federal law was making it more difficult to repair or replace MV fixtures. According to witness Cowling in this rate case, approximately 157,000 MV fixtures served under Schedule OL remain to be replaced, and that at the current replacement rate, it would take another 22 years to completely replace all MV fixtures.

DEC is also proposing to include the 60,000 MV fixtures served under Schedule PL in its replacement plan, and to complete the replacement by the end of 2023. Witness Cowling states that it is more cost-effective to replace MV fixtures in one geographic area at a time, rather than on a fixture-by-fixture basis as they fail.

Q. WHAT IS THE LIKELY IMPACT OF THIS MORE AGGRESSIVE APPROACH TO REPLACING MV FIXTURES?

A. The Company's proposal will increase the cost for the majority of lighting customers. The comparable LED fixture that would replace the MV fixture generally has a higher monthly rate for service. In response to the Public Staff's data request, the Company provided a rate and revenue comparison of fixtures impacted by the

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replacement program. Depending upon the particular fixture being replaced, I determined the increase to be between 21% and 64%.

Municipal customers served under Schedule PL stand to be the most negatively impacted by the replacement program. In response to the Public Staff's data request, the Company also provided a customer-specific analysis of the impact. Of the approximately 500 municipalities reviewed, all but 10 would see some increase in their lighting service bill. Of the 490 customers seeing an increase, 440 of those would see increases ranging from a few dollars per year to approximately $5,000 per year. The remaining 50 customers would see increases of $5,000 to $200,000 per year.

Q. HAS DEC INCLUDED ANY ADDITIONAL REVENUE IN THIS CASE TO BE REALIZED AS A RESULT OF THIS PROACTIVE REPLACEMENT PROGRAM?

A. No. The Company did not make any pro forma adjustment to recognize the potential revenue increase associated with this more aggressive MV replacement program. In response to the Public Staff's data request, the Company estimated the revenue impact for Schedule PL to be an additional $1.4 million per year by the conclusion of the program in 2023. Pro forma revenue adjustments are generally appropriate if the change causing the revenue impact is known and measureable; however, because the timing of the

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impact is likely to be at least 2 to 4 years in the future, the Company's exclusion of revenues associated with the MV replacement program is appropriate for this proceeding.

Q. WHAT HAS DEC PROPOSED TO DO TO MITIGATE THESE REVENUE IMPACTS?

A. As discussed above, the Company proposes to develop a regional replacement schedule and provide municipalities with advanced notice so that they can budget for the conversion. According to witness Cowling, the conversion of MV fixtures served under Schedule PL will not take place until the Company completes the conversion of MV fixtures served under Schedule OL.

Q. DO YOU AGREE WITH THE COMPANY'S PROPOSAL?

A. Yes. Generally, I believe the Company's proposal to accelerate the conversion of MV fixtures to LED served under Schedules OL and PL is reasonable. However, I have two recommendations regarding the Company's proposed MV replacement program.

First, to mitigate the increase in the cost of the conversion the Company should address the RORs for the lighting class and rate schedules. To the extent possible, I recommend that the Company

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reduce its rates for fixtures served under Schedules FL,[6] GL, OL, and PL such that the resulting RORs are within 10% of the overall ROR for the North Carolina Retail jurisdiction. However, no rate should be lower than the cost to serve that rate schedule.

Second, I recommend that the Commission require the Company to file semi-annual reports on the progress of its MV replacement program. The reports should discuss the geographic areas that are targeted in the next six months, the number of fixtures to be replaced, the number and type of fixtures used to replace existing MV fixtures, and an estimate of the revenue impact associated with those fixtures on an annual basis.

Q. WHAT OTHER CHANGES TO LIGHTING SERVICES HAS THE COMPANY PROPOSED?

A. The Company proposes to close Schedules FL and NL in this proceeding. Fixtures now served under Schedule FL will be migrated onto Schedules GL and OL. Witness Cowling indicates that this change is primarily an administrative change to make it easier for customers to understand the lighting services and options available.

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[6] If approved in this proceeding, fixtures currently served under Schedule FL will be migrated to Schedules GL and OL.

The Company also proposes to close Schedule NL to new customers and maintain the rate schedule for the customers now served under Schedule NL. This schedule was originally approved as a pilot schedule to introduce LED technology. There are approximately 400 fixtures served under Schedule NL for seven customers. These fixtures are generally non-standard fixtures. The Public Staff does not object to either of these proposals.

Q. ARE THERE ANY OTHER ISSUES THE COMPANY DID NOT DISCUSS IN ITS TESTIMONY REGARDING LIGHTING THAT NEED TO BE ADDRESSED?

A. Yes. The Company's filing in this proceeding did not address the alignment of rates for the same fixtures served under Schedule GL and Schedule PL.

Q. PLEASE EXPLAIN THE ISSUES ASSOCIATED WITH ALIGNING SCHEDULES GL AND PL.

A. In the Sub 909 rate case, the Commission directed the Company to begin phasing in rate equivalency for the same fixtures served under both Schedules GL and PL. Schedule PL is an older lighting rate schedule that socialized the costs of poles and underground services. In the Sub 909 case, DEC proposed Schedule GL to begin separating these charges such that customers were responsible for specific services requested by the customer (new poles or

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underground). Schedule PL was structured using a "postage stamp rate" approach[7]. Schedule GL disaggregated the fixture, pole, and underground service costs and associated rates from each other.

The Commission closed Schedule PL to new installations in the Sub 909 rate case in an attempt to transition customers to Schedule GL. In the Sub 1026 rate case, the Company made some progress toward bringing the rates into parity. However, the structural differences between Schedules GL and PL have made further movement toward parity difficult.

A review of the proposed rates for LED fixtures on existing poles served under Schedules GL and PL indicate that the rates for Schedule PL are slightly higher than those on Schedule GL. However, underground services under Schedule GL have LED fixture rates that are generally $10 per fixture higher than the rates for underground services served under Schedule PL. The proposed rates for certain HPS fixtures served under both rate schedules suggests the rates for fixtures on existing poles are slightly lower for Schedule GL than for Schedule PL. However, underground services are generally greater under Schedule GL than they are for Schedule PL. This illustrates the difficulty associated with trying to change

[7] "Postage stamp rate" means a rate that does not differentiate among the individual components of the utility services provided to the customer.

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rates from a structure that contains socialized cost elements to one that does not.

Q. WHAT IS YOUR RECOMMENDATION REGARDING SCHEDULES GL AND PL?

A. I recognize the difficulty and potential revenue impact on customers served under Schedule PL. However, the rate schedule under which a particular LED fixture is served should not be the determining factor for the rate charged for that fixture, absent extraordinary circumstances that distinguish service under different schedules. Such circumstances do not apply to the LED fixtures in question in this case, as they have been incorporated into both Schedules GL and PL only recently. Other than structural differences between Schedules GL and PL, the only characteristic that seems to distinguish the two schedules is the length of time a customer has been served under one schedule versus the other, which is not a valid reason in and of itself for differing rates for the same fixtures. The cost to serve the fixture should be the primary consideration in establishing the rate to be charged.

Therefore, I recommend that the Commission require the Company continue to meet with its municipal customers to evaluate changes to Schedules PL and GL that would make the rates for individual fixtures (LED or non-LED) served under Schedule GL the same as

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for Schedule PL. The Company should also work with the municipalities to develop a proposal to consolidate Schedules PL and GL in a future proceeding.

CUSTOMER CONNECT PROJECT

Q. PLEASE DISCUSS YOUR REVIEW OF THE COMPANY'S CUSTOMER CONNECT PROJECT.

A. I have reviewed details related to the Company's proposed Customer Connect Project (CCP), including the testimony and exhibit of Company Witness Hunsicker, as well as a volume of internal and confidential information related to the Company's decision to move forward with the CCP.

DEC's existing customer information and management system (CIM or CIS) was first place into service in the mid to late 1990's. The CCP is an initiative created by DE, through its Duke Energy Business Services (DEBS) entity, to replace the current customer billing and information systems with a modern, responsive system. The CCP will be able to integrate the various customer-related functions into a platform that will provide improved customer services related to billing, management of customer data, customer relations and interactions, and the provision of information related to distributed generation. The CCP will eventually replace the existing billing and

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customer management systems of all DE affiliates except Piedmont Natural Gas Company.

The proposed CCP is being designed to utilize new technology more efficiently than the current system, which was designed to function with the technology that was readily available in the 1990's. Over the years, this technology base has expanded and the system has had to introduce "add-ons" or software updates to keep the system running. The 20 plus-year old existing system, cannot be expanded further to accommodate the current and emerging capabilities of a modern grid.

Q. PLEASE DISCUSS HOW THE CCP WOULD BE DIFFERENT FROM THE CURRENT CIS AND HOW IT WOULD AFFECT CUSTOMERS.

A. The proposed CCP has been designed to leverage the capabilities available in the new smart meters the Company are deploying. The CCP, along with smart meters and other behind-the-scenes processes, are being designed to provide customers with enhanced service by providing both the Company and its customers with more information regarding individual account history. I will discuss details of the Company's smart meter deployment later in my testimony.

The CCP is also being designed with a more universal, yet simpler, platform that will greatly reduce the need for manual billing, which is

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the current process being used for customers with grid-connected distributed generation systems. Further, the CCP is designed to assist the Company in its commitment to develop new rate design options that will allow customers to better understand and manage their electricity consumption and how pay for it. To this end, the Company intends to use the CCP to develop analytics that will be able to understand customer preferences, provide more specific outage notification, develop bills for services based on when the customer wants the bill to become due (i.e. pick your own due date), provide different payment options, and market certain goods and services to the customer based on these interactions and customer usage patterns. The Company also expects a significant decrease in the number of manual billings that will be necessary.

Q. DESCRIBE SOME OF THE SHORTCOMINGS ASSOCIATED WITH THE CURRENT CIS USED BY DEC.

A. In response to a Public Staff data request, the Company indicated that the current CIS is no longer supported by vendors. DEC also stated that the CIS is incapable of efficiently handling many of the utility services being requested by its customers such as smartphone applications, more detailed usage information, payment options, and allowing customers to select preferences of communication with the Company. The CIS is capable of only communicating with meters in

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order to render a monthly bill, as opposed to being a portal for customer information and services. The CIS is also unable to help manage energy consumption, integrate renewable generation, develop micro-grids, interact with programmable thermostats, or provide access to the customer’s account through internet- and smartphone-based platforms.

Q. WHAT IS THE COMPANY'S PROPOSED SCHEDULE OF IMPLEMENTATION?

A. According to Witness Hunsicker and in response to a Public Staff data request, by the end of 2018, DEC intends to develop the analytics necessary to initialize the CCP, and then begin merging existing customer data with new data in a way that the customer will begin to see a difference in how they interact with the Company. This will allow customers to start observing changes in the way they interact with the Company. New billing formats and payment options are not expected to be available until later. Since this is a DE-wide undertaking, DEC not is expected to realize the full potential benefit and core functionalities of the CCP until sometime in 2022.

Q. DOES THE PUBLIC STAFF SUPPORT DEC’S FUTURE IMPLEMENTATION OF THE CCP?

A. Yes.

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Q. IS THE CCP USED AND USEFUL AS OF THE END OF THE TEST YEAR?

A. No. The CCP was not used and useful as of December 31, 2016. According to DEC, the CCP is likely to become only partially used and useful as of the end of 2018. The full capabilities of the CCP are not expected to be used and useful in the DEC service territory until the 2022. The Company is still uncertain exactly when DEC will be able to fully utilize the various components of the CCP.

Q. WHAT ARE THE COSTS AND BENEFITS ASSOCIATED WITH THE CCP?

A. DEC indicated that the costs of the CCP for DEBS would be $840.5 million, excluding financing. The North Carolina retail jurisdictional responsibility for DEC's allocated share of the total DEBS cost would be approximately 26% using a customer-count allocation factor. Company witness Hunsicker states that the NC retail jurisdiction's allocation would be approximately $220 to $230 million.

DEC also provided the Public Staff a confidential calculation of the benefits the Company expects from the CCP over a 20-year period.

Q. DO YOU HAVE ANY RECOMMENDATIONS REGARDING THE DESIGN AND DEPLOYMENT OF THE CCP?

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A. Yes. While the Public Staff is generally supportive of deploying the CCP, I recommend that the Company take all necessary precautions to ensure that customer data remains secure. The Company also should ensure that sharing of customer information as envisioned by the CCP complies with DEC's code of conduct.

Also, I recommend that DEC provide semiannual reports on the status of implementation of the CCP. These reports should include the following information associated with designing, building, testing, and implementation of the CCP:

1. Activities undertaken in the past six months;

2. Activities planned for the next six months, updated in future reports as appropriate;

3. Expenditures (by category for capital and O&M) for both internal and external services, and equipment incurred in the last six months;

4. The project-to-date expenditures (by category for capital and O&M) for both internal and external services, labor, and equipment;

5. Any changes to contracts with vendors, and the impact to the costs and schedule those changes will cause upon the CCP;

6. Description of the functionalities that are operational and available for use by the Company and/or customers;

7. Description of the functionalities that are not yet operational, why they are not yet operational, and when DEC expects them to be operational;

8. Metrics associated with the customer traffic, use of services, and any other information that would

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provide an understanding of how customers are interacting with the Company; and

9. Any other information the Company believes to be appropriate.

Q. DID DEC INCLUDE ANY COSTS IN THIS CASE ASSOCIATED WITH THE DEVELOPMENT OF THE CCP?

A. Yes. According to witness McManeus, DEC has incurred $4,400,000 of expense in the test year related to the initial work on the CCP by Company staff. An additional $8,942,590 has been incurred through November 2017, bringing the total amount incurred to approximately $13.3 million. I believe this amount is reasonable. However, Public Staff witness Boswell has included an adjustment to exclude projected the CCP expenses, as explained in more detail in her testimony.

AMI DEPLOYMENT

Q. PLEASE DISCUSS THE COMPANY'S WORK TO REPLACE ITS EXISTING METERS WITH NEW SMART METERS.

A. DEC began an initiative in 2013 to replace all of its electric service meters in its North Carolina and South Carolina service territories with smart meters (also termed "AMI" for "advanced metering infrastructure"). The Company has indicated that its initiative to replace the existing meters with AMI is based upon its efforts to establish a two-way communications platform that will provide

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customers with usage information, service quality-related information such as outages, and new billing and payment options. According to witness Schneider, this initiative will provide customers with greater convenience, control, and transparency regarding their utility service. The Company's current non-AMI meters are incapable of two-way communications.

Through June 30, 2017, DEC has installed approximately 750,000 AMI meters in its North Carolina service territory (37% of the total meters) and approximately 440,000 AMI meters in its South Carolina service territory (73% of the total meters). The Company has spent approximately $297 million for its new AMI meters and communications infrastructure. Approximately $74 million of this amount is already included in the Company's rate base through the end of the test year. Updating the case through November 2017 will add an additional $123 million to rate base for AMI meters. The Company expects to complete its AMI conversion initiative by the middle of 2019.

The existing metering equipment, known as AMR (automated meter reading), was first installed in the early 2000s. At that time, DEC's AMR deployment consisted of a combination of replacing analog meters with digital AMR meters, and also retrofitting existing analog meters with communication devices that made those meters AMR

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capable. Those meters have remained in service until the Company began replacing them with AMI meters.

Q. WHAT NEW FUNCTIONS OR SERVICES WILL AMI METERS ALLOW THE COMPANY TO PERFORM?

A. My review of this issue along with the Company's smart grid technology plan filed in October 2016 in Docket No. E-100, Sub 147[8], provided a basic understanding of what AMI meters could do that AMR meters cannot do. Identification of the functionalities of each meter type is important for use in developing a cost-benefit analysis for deploying smart. The functionalities that can be provided by AMI but not AMR meters are summarized as follows:

1. Providing two-way communication that will assist with detection of outage and voltage quality;
2. Bi-directional power flows;
3. Remote connections and disconnections;
4. Tamper detection;
5. More detailed usage data (hourly and daily); and
6. Home Area Network capabilities via Zigbee radio.

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[8] I reviewed the smart grid technology plans filed by both DEC and Duke Energy Progress, LLC. These plans were very similar, and I believe that both companies are pursuing a meter replacement initiative on the same basis. Therefore, with respect to AMI meters, I have interpreted information regarding the functionalities of AMI to be applicable to both companies.

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In short, the AMI meters will allow communication and interaction with the proposed CCP.

Q. DID THE COMPANY PROVIDE A COST-BENEFIT ANALYSIS IN THIS CASE?

A. Yes. The Company provided an initial cost-benefit analysis[9] that monetized the AMI functions and included other benefits related to meter reading and account management such as reductions in O&M expenses that would result from the deployment of AMI. The results of the cost-benefit analysis indicated a net savings over the 20-year period of the analysis.

In response to the Commission's August 21, 2017 *Order Requiring Additional Information* (Sub 1115 Order) in Docket Nos. E-7, Sub 1115 and E-100, Sub 147, the Company provided an updated cost-benefit analysis on December 15, 2017 that responded to Commission concerns regarding the estimates of non-technical losses (NTLs) and revenue impacts.

Q. DO YOU HAVE ANY CONCERNS WITH THE COST-BENEFIT ANALYSIS USED BY THE COMPANY TO JUSTIFY DEPLOYMENT OF AMI METERS AT THIS TIME?

[9] DEC filed a cost-benefit analysis as an exhibit to its Smart Grid Technology Plan Supplement, filed May 5, 2017 in Docket No. E-100, Sub 147.

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A. Yes. A substantial amount of the expected benefit identified by the Company in the analysis is the Company's efforts to reduce theft and other losses of energy and revenue due to meter tampering. The basis of the Company's estimate is an EPRI study[10] from 2008 that estimates a reduction of lost revenues by as much as 2%.

Unfortunately, the study is almost ten years old and predates the initial industry deployment of AMI meters that began in 2013. There is little definitive or contemporaneous data that would provide more clarity on this estimate and the Company has included no experiential data from the industry. If the estimate of these "non-technical losses" is true, then the savings from reducing lost sales and revenues would be a direct benefit to customers. If these benefits do not materialize, then the benefit of AMI meters may be overstated. Also, in a confidential response to the Public Staff's data requests, DEC indicated that it had not performed any specific analysis to identify non-technical losses with the AMI deployment thus far. However, DEC did acknowledge that analytics were underway to assess the revenue implications associated with smart meters from recovery of revenue losses.

[10] "Advanced Metering Infrastructure Technology – Limiting Non-Technical Distribution Losses in the Future," Electric Power Research Institute, December 2008 (EPRI Study).

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Further, the Company's December 15, 2017 response to the Sub 1115 Order, stated why the Company relied on the EPRI Study and why a more detailed study of NTLs was not conducted. First, the work necessary to more specifically quantify NTLs is identified as "significantly complex and arduous." Second, NTLs could not be precisely isolated unless an analysis of individual cases could be performed. Third, the analytics associated with revenue protection were continuing to develop along with the deployment of AMI. Notwithstanding these points, the Company attempted to recalculate the NLTs in its cost-benefit analysis. The results reduced the percentage of NLT from 2.0% to 1.26%.

In the December 15, 2017 analysis, the Company recalculated the net present value of its AMI deployment program. Pursuant to the Commission's directive in the Sub 1115 Order, the Company recalculated the cost-benefit analysis using the revised NTL percentage, cost of replacing AMI meters at the end of 15 years, and the costs associated with software replacement and the cellular meter costs. The result was a negligible cost over the 20-year evaluation. The May 5, 2017 analysis, which included a small benefit, did not include replacing meters after 15 years, or the other cost inputs requested in the Sub 1115 Order. While a direct comparison of the two analyses is difficult, I believe both represent a fair analysis and both indicate a nearly break-even cost-benefit.

Q. WHAT IS YOUR OPINION REGARDING THE COMPANY'S COST-BENEFIT ANALYSES?

A. I am generally supportive of the analyses provided by the Company. I also believe that a cost-benefit analysis itself, while helpful and necessary in the decision to replace meters, should not be the sole basis used to justify replacement of the existing AMR meters. The Company's commitment to new rate designs, the changing nature of the utility business, and the need to properly identify cost causation and to appropriately price the goods and services provided by the Company, must also be considered. I consider these to be benefits that are not easily quantified in terms of a strict cost-benefit analysis.

The Public Staff is, however, concerned that the Company will not immediately maximize the benefits available to customers from AMI. The functions and benefits included by the Company in its analysis suggest DEC will initially primarily utilize the benefits of AMI that improve operations and reduce the expenses of the Company. While customers will undoubtedly benefit from this approach, without providing the means for customers who seek to actively manage their use of electricity to save on their power bills, the benefits of AMI will not be fully realized by customers. In other words, without access to all of the functionalities of AMI, customers will not experience the greater convenience and control of usage that should be available to

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them.

The Company has committed to develop new and innovative rate designs, which should contribute toward maximizing this direct customer benefit. For example, DEC should produce rate designs that include new TOU rate structures that provide stronger price signals to shift load. It should also result in new payment options including allowing customers to prepay for electricity. These two options should be available for both the residential and general service rate classes. DEC should also produce informational tools and applications that provide more granular and timely data to allow customers greater insight and control over their actual usage, regardless of whether such customers avail themselves of new and innovative rate designs. The Public Staff's support for the AMI deployment is predicated on maximizing these non-quantifiable benefits for customers, as well as reducing NTLs.

Another concern is related to customers who opt-out of having an AMI meter. If a significant number of customers elect to opt-out of having an AMI meter, the benefits of AMI meter deployment will be diminished. DEC filed for approval of Rider MRM[11], which would allow customers who desire to opt-out of having a smart meter to pay a monthly fee to have a fully manual meter. Numerous customer

[11] Docket No. E-7, Sub 1115.

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letters have been filed in the Sub 1115 docket. The Public Staff filed its comments on this matter on October 24, 2016, supporting an opt-out policy, and generally supporting DEC's request for Rider MRM, which includes recovering the costs of the opt-out policy from the customers who choose to opt-out.

As part of its present deployment of AMI meters, the Company and the Public Staff have worked out an arrangement where the Company would bypass any customer desiring not to have an AMI meter. That customer would simply keep the existing AMR meter. However, as the Company's AMI deployment continues and more customers receive AMI meters, the need to address those bypassed AMR meters will become more urgent. Therefore, I encourage the Commission to conclude the AMI opt-out proceeding in the Sub 1115 docket by ruling on the matter as part of this general rate case.

Q. DO YOU HAVE ANY COMMENTS REGARDING THE INVENTORY OF EXISTING AMR METERS AND THE COMPANY'S REQUEST TO ESTABLISH A REGULATORY ASSET FOR ITS EXISTING METERS?

A. Yes. As a general principle, customers should receive the full benefits of AMI meters prior to being asked to pay for the system-wide replacement of AMR meters that have not reached the end of their useful lives. Company witness McManeus has requested

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approval of a regulatory asset for the remaining book value of existing AMR meters following full scale deployment of AMI. As I discussed earlier, the Company provided its cost-benefit analysis related to the deployment of AMI, which concluded a net benefit that existed from the replacement of existing AMR meters. Over the three-year period the Company expects to deploy AMI meters, Witness McManeus indicates the Company expects the balance of the regulatory asset to be close to zero. Public Staff witness Maness discusses the regulatory asset in more detail in his testimony.

Q. WHAT ARE YOUR RECOMMENDATIONS REGARDING THE AMI DEPLOYMENT?

A. Except for the concerns I have raised concerning DEC's cost-benefit analysis, I believe the Company has made a reasonable assessment of the costs and benefits associated with its proposed deployment of AMI. It will be incumbent upon DEC to maximize the benefits not only by eliminating or reducing expenses to provide utility service and NTLs, but also by providing new opportunities for customers to use both AMI meters and CCP so that they see a real benefit on their bills. Customers who are more aware of their energy use should be empowered to make more informed choices on how they use and pay for energy. AMI and the CCP are technologies that should be able to bring about the greater convenience, choice, and

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transparency that DEC has indicated it seeks with these investments. Therefore, I do not object to inclusion of the Company's AMI costs incurred to date and included in this filing.

At the time the Company files its next rate case, I recommend that DEC include the following information as part of its rate case filing:

1. A cost-benefit analysis that is based on the actual AMI deployment costs incurred;

2. A determination of the actual non-technical loss benefits that are realized, including sample case studies that would illustrate those benefits and how those benefits have impacted the Company's base revenue items that comprise the NTLs;

3. The status of deploying new and innovative TOU rates and other prepayment options; and,

4. An analysis of the coordination between the Customer Connect Project and AMI initiative regarding the deployment of new services, tools, and applications that provide customers with more information on their usage, payment options, and new rate designs that encourage energy efficiency or shifting load.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes, it does.

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Appendix A

JACK L. FLOYD

I am a graduate of North Carolina State University with a Bachelor of Science Degree in Chemical Engineering. I am licensed in North Carolina as a Professional Engineer. I have more than 17 years of experience in the water and wastewater treatment field, nine of which have been with the Public Staff's Water Division. In addition, I have been with the Electric Division for almost 14 years.

Prior to my employment with the Public Staff, I was employed by the North Carolina Department of Natural Resources, Division of Water Quality as an Environmental Engineer. In that capacity, I performed various tasks associated with environmental regulation of water and wastewater systems, including the drafting of regulations and general statutes.

In my capacity with the Public Staff's Water Division, I investigated the operations of regulated water and sewer utility companies and prepared testimony and reports related to those investigations.

Currently, my duties with the Public Staff include evaluating the operation of regulated electric utilities, including rate design, cost-of-service, and demand side management and energy efficiency resources. My duties also include assisting in the preparation of reports to the Commission; preparing testimony regarding my investigation activities; reviewing Integrated Resource Plans; and making recommendations to the Commission concerning the level of service for electric utilities.

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